Energy 75 (2014) 419–429

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Prediction of thermophysical properties of saturated steam and wellbore heat losses in concentric dual-tubing steam injection wells

Hao Gu [a,*], Linsong Cheng [a], Shijun Huang [a], Baojian Du [a], Changhao Hu [b]

[a] Department of Petroleum Engineering, China University of Petroleum, Beijing, 18 Fuxue Road, Changping 102249, China
[b] Research Institute of Petroleum Exploration & Development, Liaohe Oilfield Company, PetroChina, Panjin 124000, China

ARTICLE INFO

Article history:
Received 16 April 2014
Received in revised form
27 July 2014
Accepted 30 July 2014
Available online 28 August 2014

Keywords:
Concentric dual-tubing steam injection well
Thermophysical properties
Wellbore heat losses
Pressure gradient in annuli
Insulation materials

ABSTRACT

Concentric dual-tubing steam injection is important in the process of thermal recovery for heavy oils. This paper firstly presented a mathematical model to predict thermophysical properties of saturated steam (i.e. steam pressure, temperature and quality) and wellbore heat losses in CDTSIW (concentric dual-tubing steam injection wells). More importantly, a semi-analytical model for estimating pressure gradient for steam/water flow in annuli was developed. Then the mathematical model is solved using an iterative technique. Predicted results were compared with measured field data to verify the accuracy of the model. The results indicate that the direction of heat transfer between fluids in the integral joint tubing and in the annulus depends not only on wellhead injection conditions but on temperature drop in each tubing. In addition, the steam qualities in CDTSIW are significantly influenced by heat exchange between fluids in dual tubing, which can cause steam boiling or condensation. Moreover, the paper shows that to effectively reduce the wellbore heat losses and to ensure high bottomhole steam qualities in Well Xing 67 of Liaohe Oilfield, the thermal conductivity of insulation materials should be less than 0.7 W/(m K).

1. Introduction

Steam injection techniques are widely used in the process of thermal recovery for heavy oils, such as in steam stimulation, steamflooding and steam-assisted gravity drainage [1,2]. One of the most important reasons is that high-temperature steam carries much heat, and injecting the heat into oil layers can reduce the viscosity of heavy oil whose mobility is relatively low under initial formation temperature. However, traditional single-tubing steam injection technique is not perfect. For instance, in Liaohe Oilfield, Panjin, single-point steam injection method applied in horizontal wells always leads to obvious steam fingering phenomena and uneven exploitation of oil layers [3], especially in seriously heterogeneous reservoirs. In addition, single-tubing steam injection is not the best choice for multiple-oil-layer steamflooding when low cost and easy control are taken into account [4,5]. In these cases, concentric dual-tubing steam injection may be one of the most effective measures to alleviate these problems. As steam flows in a CDTSIW (concentric dual-tubing steam injection well), the thermophysical properties of saturated steam (i.e. steam pressure, temperature and quality) always change with well depth, therefore, the first task in the design of steam injection projects is to predict these properties before steam enters the oil layers [6]. Also, not all heat carried by steam injected from wellhead can enter the oil layers, there are still some heat losing from wellbore to the surrounding formation, so the second task is to predict wellbore heat losses.

For the above two tasks in the design of steam injection projects, some classic researches have been conducted. Ramey [7] firstly presented an approximate method for predicting fluid temperature in wellbores on the assumption that heat transfer inside the wellbore is steady-state, while heat transfer in the formation is unsteady radial conduction. His work laid a foundation for subsequent researchers, although he only considered single phase (ideal gas and incompressible liquid) flow in the wellbore. Satter [8] took into account the effect of phase change and suggested a method for estimating steam quality, but he ignored kinetic energy change when modelling steam quality based on energy conservation principle. In addition, his assumption that pressure drops due to potential energy change and friction loss can cancel each other may not be true in the case of a deep well or a high injection rate. Hasan and Kabir [9], whose work is very important in determining the

* Corresponding author. Tel./fax: +86 10 89733726.
E-mail address: guhao110110@163.com (H. Gu).

http://dx.doi.org/10.1016/j.energy.2014.07.091
0360-5442/

Nomenclature

a	geothermal gradient, K/m
C_J	Joule–Thompson coefficient, K/Pa
C_p	heat capacity at constant pressure, J/(kg K)
D_e	equivalent hydraulic diameter, m
D_{ii}	inside diameter of integral joint tubing, m
dQ_{an}/dz	wellbore heat losses or rate of heat flow from annulus to the surrounding formation, W/m
dQ_{ij}/dz	rate of heat flow from fluid in the integral joint tubing to the annulus, W/m
f_{tp}	two-phase friction factor, dimensionless
$f(t)$	transient heat-conduction time function, dimensionless
g	gravitational acceleration, m/s^2
h_{an}	specific enthalpy of mixture fluid in the integral joint tubing, J/kg
h_c	convective heat transfer coefficient, W/(m^2 K)
h_{fii}	forced-convection heat transfer coefficient on inside of integral joint tubing, W/(m^2 K)
h_{fio}	forced-convection heat transfer coefficient on outside of integral joint tubing, W/(m^2 K)
h_{f1i}	forced-convection heat transfer coefficient on inside of tubing 1, W/(m^2 K)
h_r	radiative heat transfer coefficient, W/(m^2 K)
h_s	specific enthalpy of dry steam, J/kg
h_w	specific enthalpy of saturated water, J/kg
J_0	first kind Bessel functions of zero order
J_1	first kind Bessel functions of first order
L_v	latent heat of vaporization of steam, J/kg
N	segment numbers or data numbers
p	pressure, Pa
r	radius distance from the center of the wellbore, m
r_{1i}	inside radius of tubing 1, m
r_{1o}	outside radius of tubing 1, m
r_{2i}	inside radius of tubing 2, m
r_{2o}	outside radius of tubing 2, m
r_{ci}	inside radius of casing, m
r_{co}	outside radius of casing, m
r_h	outside radius of the wellbore, m
r_{ii}	inside radius of integral joint tubing, m
r_{io}	outside radius of integral joint tubing, m
t	injection time, h
T_0	surface temperature of the formation
T	temperature, K
T_{ei}	initial temperature of the formation, K
T_h	wellbore/formation interface temperature, K
u	dummy variable for integration, dimensionless
U_{2o}	over-all heat transfer coefficient between the annulus and the cement/formation interface, W/(m^2 K)
U_{io}	over-all heat transfer coefficient between inside and outside of integral joint tubing, W/(m^2 K)
v	velocity, m/s
v_{sgan}	superficial gas velocity in the annulus, m/s
v_{sgij}	superficial gas velocity in the integral joint tubing, m/s
W	mass flow rate, kg/s
x	steam quality, dimensionless
$x_{an}(0)$	wellhead steam quality in the annulus, dimensionless
$x_{ij}(0)$	wellhead steam quality in the integral joint tubing, dimensionless
y	dependent variables
Y_0	the second kind Bessel functions of zero order
Y_1	the second kind Bessel functions of first order
z	variable well depth from surface, m

Greek letters

α	thermal diffusivity of the formation (m^2/h)
λ_{cas}	thermal conductivity of casing, W/(m K)
λ_{cem}	thermal conductivity of cement sheath, W/(m K)
λ_e	thermal conductivity of formation, W/(m K)
λ_{ins}	thermal conductivity of insulation materials, W/(m K)
λ_{tub}	thermal conductivity of tubing wall, W/(m K)
ρ	density, kg/m^3
ρ_{ns}	no-slip density of mixture fluid, kg/m^3
ω	ratio of the formation heat capacity to the wellbore heat capacity, dimensionless
τ_D	dimensionless time
θ	well angle from horizontal

Subscripts

ij	integral joint tubing
an	annulus
m	mixture
mea	measured value
pre	predicted value
s	dry steam
w	saturated water

wellbore heat losses, established a formation heat-transfer model and derived an expression for formation temperature distribution as a function of radial distance and injection time, although the effect of wellbore heat capacity was not included in their study. In recent years, Cheng et al. [10,11] improved the formation heat-transfer model by considering the wellbore heat capacity and proposed a novel transient heat-conduction time function that will be adopted to calculate the wellbore heat losses in this paper.

The above classic studies are significant bases of predicting thermophysical properties of saturated steam and wellbore heat losses in CDTSIW. However, in order to successfully accomplish the two tasks, we must also overcome a critical bottleneck: how to accurately estimate pressure gradient for steam/water flow in downward annuli. In fact, it is not always easy to solve this problem and this difficulty can further influence the whole predicted results. Caetano [12], Hasan and Kabir [13], Antonio et al. [14,15] and Yu et al. [16] presented different mechanistic models to estimate pressure gradient for two-phase flow in annuli. In their models, the flow mechanism and the transition criterion for each flow pattern were researched independently, and the governing equations for pressure drop and flow parameters for a given flow pattern were also suggested. However, the calculation methods for intermediate variables were very complicated and time-consuming. More importantly, what they studied was upflow, which differs from downward steam/water flow, and the difference in flow direction can affect buoyancy effect of gas bubbles, bubble distribution across the channel, flow patterns and final computational model [17]. Besides mechanistic models, empirical correlations were also adopted in previous works. Griston et al. [5] and Wu et al. [18] treated the annuli as pipes based on equivalent hydraulic diameter concept and calculated the pressure drop for two-phase flow in annuli with the methods that had been extensively employed in pipe systems. While for downward or upward gas/liquid flow in pipes, the calculation methods for pressure drop are relatively simple and have been well verified and improved in practice [19–21]. Orkiszewski [22], Beggs and Brill [23] and Hasan et al.